REPORT

ON THE EARLY REMOVAL

OF THE PETROLEUM AND GAS REVENUE TAX

Petroleum Monitoring Agency Canada
Agence de surveillance du secteur pétrolier Canada
Canada

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Report to

The Honourable Marcel Masse

Minister of Energy, Mines and Resources Canada

on the

Petroleum Industry's Reinvestment Intentions

following the early removal of

The Petroleum and Gas Revenue Tax

PETROLEUM MONITORING AGENCY
CANADA

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Agence de surveillance du secteur pétrolier Canada

The Honourable Marcel Masse
Minister of Energy, Mines and Resources
Ottawa, Ontario

Dear Minister:

In response to your request of September 19, 1986, I am pleased to submit the attached report on the petroleum industry's reinvestment intentions following the accelerated elimination of the Petroleum and Gas Revenue Tax.

The examination of the petroleum industry's response was conducted through a series of interviews with senior executives of the 40 largest oil and gas companies. The Agency's extensive data base covering more than seven years of income and expenditure data was a principal component of this interview process.

We have concluded that the additional cash flow accruing to the industry as a result of the early elimination of the tax will be used to maintain and increase capital expenditures and staff levels and not to raise dividends or other payouts to shareholders.

Information obtained through our regular semi-annual monitoring surveys during the next two years will indicate the degree to which companies have fulfilled their commitments.

Respectfully submitted,

George A. Reinecke
Director, Monitoring

May 20, 1987

Canada

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1. INTRODUCTION

On September 8, 1986, the Honourable Marcel Masse, Minister of Energy, Mines and Resources, announced that the Petroleum and Gas Revenue Tax (PGRT) would be eliminated effective October 1, 1986, twenty-seven months ahead of schedule. The decision to remove the tax resulted from the deteriorating financial situation of the Canadian petroleum industry following the collapse of oil prices in early 1986.

This announcement followed assurances by industry organizations and representatives of major oil and gas producers that, in accordance with historical behaviour, savings from the elimination of the PGRT would be reinvested in exploration and development activity.

At the time of the announcement of the elimination of the tax, the Minister of Energy, Mines and Resources estimated that as a result of the measure, industry cash flow would rise by hundreds of millions of dollars over the following two and a half years. This additional cash flow would both preserve and create jobs.

The Minister said that he would be asking the Petroleum Monitoring Agency (PMA) to provide him with "periodic reports on industry reinvestment behaviour over each of the next two years". On September 19, Minister Masse wrote to the PMA confirming this request.

2. BACKGROUND

A. The Effects of the Price Decline

In the first six months of 1986, the Canadian petroleum industry experienced the most dramatic downturn in its history. In January 1986, the wellhead price of oil averaged $33 (US$23.50)/bbl. Six months later, in July, the wellhead price had plummetted, averaging $14.60 (US$10.55)/bbl. In the course of that overall decline, prices had shown considerable volatility, sometimes moving several dollars per barrel in a single day. The extent of the decline exceeded the most pessimistic expectations of the majority of companies. Furthermore, there was no indication that prices would rebound quickly, significantly, or at all.

The industry's upstream net income for the first six months of 1986 was down 56% to $640 million and its cash flow was down 38% to $2.9 billion. These sharp reductions in cash flow and profitability substantially affected the industry's ability and willingness to invest in new exploration and development, and to undertake major energy projects. However, because of commitments to capital projects at the beginning of the year, first half 1986 capital expenditures were down only 14% to $4.4 billion.

Among activities which were put on hold as a result of the price decline were development of the four major oil sands deposits in Alberta and the heavy oil regions of Saskatchewan. Esso had planned to complete four more phases at Cold Lake; BP and Petro-Canada were planning to expand their Wolf Lake project; and Shell Canada planned to increase its Peace River project. Suncor, Dome, Murphy, Amoco and PanCanadian also deferred projects. Since then, however, some of those projects have been reactivated.

Oil and gas producers were not alone in experiencing a loss in revenues. A report prepared for the Governments of Alberta and Canada in September 1986 showed that Alberta-based oil and gas field services and supply contractors faced a 42% decline in revenues from 1985 to 1986, with a further 3% decrease foreseen for 1987.(1) The same report showed oil and gas field equipment manufacturers' revenues were projected to decrease by 35% in 1986.

The decline in activity led to a serious employment problem. Total Alberta oil and gas industry employment fell 26%, from 90,000 in December 1985 to 67,000 in June 1986.(1) Current estimates, based on input-output analysis, indicate that Alberta's employment loss in 1986 was in excess of 30,000 jobs.

Since the fall of 1986, however, there has been reason for cautious optimism as crude oil prices have stabilized in the range of US$16-18/bbl. During the first quarter of 1987, prices for West Texas Intermediate averaged close to US$18, and Canadian wellhead prices exceeded $22/bbl., about US$17.(2) But weaker prices for natural gas and gas derivatives will be more fully felt in 1987 than in 1986 and may offset any improvement from firmer oil prices.

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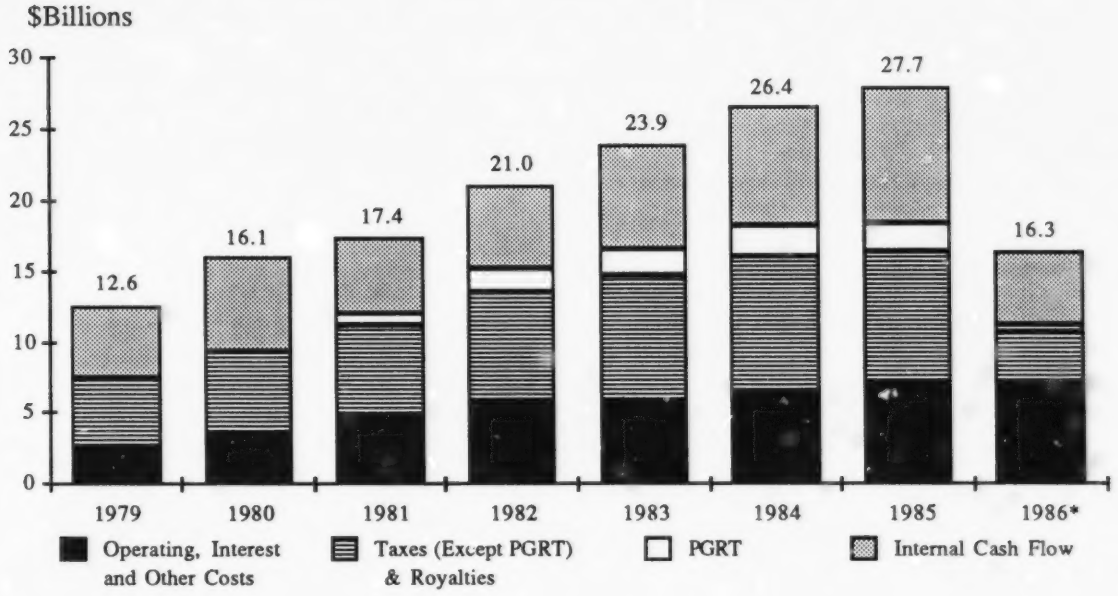
(1) The Impact of Low Oil and Gas Prices on the Oil and Gas Industry in Alberta, CERI Energy Research Ltd., September 1986.
(2) Energy, Mines and Resources, Oil Branch.

B. Impact of PGRT on Internal Cash Flow

The PGRT was one of several special taxes and charges introduced in 1980 by the previous government under the National Energy Program (NEP). Others included the Incremental Oil Revenue Tax, the Natural Gas and Gas Liquids Tax, the Petroleum Compensation Charge and the Canadian Ownership Special Charge. The introduction of these taxes reflected, to a considerable extent, that government's desire to capture a larger share of what was then expected to be a steadily growing level of oil and gas revenues. These tax measures were accompanied by the Petroleum Incentives Program and by other policy instruments intended to increase Canadian ownership and control of the oil and gas industry.

COMPONENTS OF UPSTREAM REVENUE



*Preliminary

The imposition of the PGRT had a dampening effect on the industry's upstream internal cash flow. While in 1979 and 1980, cash flow represented just over 40% of revenues, this ratio declined to about 31% following the introduction of PGRT (for further detail, see Appendix B).

The PGRT differed from the corporate income tax in that it was based on production revenue, rather than profits. Consequently, as global oil markets softened, prices fell and Canadian industry profits declined, the Government continued to receive substantial revenues from this tax. Accordingly, cash flow as a percentage of revenue decreased from its 1985 level of 34% to 32% during the first half of 1986. The elimination of the PGRT should bring the 'cash flow to revenue' ratio closer to historical levels, subject of course, to continued price and output volume stability.

C. Increasing Market Orientation

With the Western Accord of March 28, 1985, the federal government moved to revamp the oil industry's operating environment. The Accord, a comprehensive agreement among the Governments of Canada, Alberta, British Columbia and Saskatchewan, represented a major step in the implementation of a market-oriented energy policy in that it altered substantially the NEP energy pricing and fiscal regime.

On energy pricing, the Accord provided for the total deregulation of oil pricing and marketing, effective June 1, 1985, and put into motion a process leading to a more market-oriented approach to natural gas pricing.

The Accord established a fiscal regime which was more profit-sensitive and non-discriminatory. It removed a number of charges and most of the taxes introduced under the NEP, including the Natural Gas and Gas Liquids Tax, the Incremental Oil Revenue Tax, the Canadian Ownership Special Charge, the Crude Oil Export Charge, and the Petroleum Compensation Charge.

Regarding the PGRT, measures were taken to phase it out. The PGRT was eliminated from new production effective April 1, 1985; for existing production, it was to be phased out by January 1, 1989. Companies in a non-taxpaying position were allowed to offset new and unused write-offs of exploration and development expenditures against PGRT.

D. Regional Considerations

The collapse in world oil prices in 1986 reduced industry cash flow and the profitability of new oil and gas projects, adversely affecting the economies of the principal producing provinces. Accelerated PGRT elimination was strongly advocated by industry and the most favoured of all proposals for industry relief, consistent with the market principles of the Accord.

The dramatic change in the economic conditions affecting the petroleum industry resulted in a review by the federal and provincial governments of existing taxes and royalties. As a result of this review, and after consultation with provincial governments, the Government of Canada decided to modify further the single remaining special tax it levied on the industry -- the PGRT.

On April 30, 1986, the Prime Minister announced measures to relieve small producers and high cost oil sands producers from the PGRT. The small producer PGRT credit was increased to $2 million, and the PGRT was lifted for Syncrude and Suncor production until the end of 1986. As well, the deduction allowed individuals in computing revenue subject to PGRT was increased from $10,000 to $40,000 annually, retroactive to January 1, 1986 (Appendix A, page 20).

Western Canadians welcomed these moves, but continued to urge quicker elimination of the PGRT. The federal government responded to these concerns by accelerating dramatically the already scheduled phase-out of the PGRT, despite its own difficult budgetary situation. On September 8, 1986, the Minister of Energy, Mines and Resources announced in Calgary that the tax would be entirely eliminated, effective October 1, 1986.(1)

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(1) Other fiscal responses included Alberta's reduction of royalty levels, the enrichment of the Alberta Royalty Tax Credit and Saskatchewan's establishment of price sensitive royalty rates. A royalty holiday on newly discovered oil was announced in both provinces. More recently, the federal government announced the Canadian Exploration and Development Incentive Program.

3. HISTORY OF THE INDUSTRY'S REINVESTMENT PERFORMANCE

PGRT relief, which resulted in higher cash flow, is only one of many factors contributing to changes in cash flow. It is therefore virtually impossible to trace a dollar of cash flow coming from lower taxes, such as PGRT, or any other source. However, a brief review of past reinvestment performance provides a basis for the examination of the industry's response to the elimination of PGRT in view of the assurances given that additional cash flow would be reinvested in accordance with historical behaviour.

Cash flow is a measure of the cash income generated by a business. It is also the maximum amount of cash available for reinvestment. Put another way, it is net income before write-offs and other non-cash charges. It is calculated by taking total revenues less cash costs such as operating costs, interest, royalties, PGRT (when applicable) and current income taxes, but before the payment of dividends.

Capital expenditures are the funds used for exploration, development and production activities and for investments in new machinery and equipment, exclusive of funds used for takeovers or the acquisition of existing property and plant. For PMA purposes, capital expenditures are considered net of incentive grants such as Petroleum Incentives Payments.

The resulting reinvestment ratio, i.e., capital expenditures divided by internal cash flow, is a key reference point for the industry's performance.

Changes in capital expenditures usually follow, with some time lag, changes in actual or anticipated levels of internal cash flow. Consequently, the ratio should not be viewed in isolation or for a single year alone. Obviously, it is not a sign of industrial health if high ratios resulted from a large drop in cash flow; nor would poor performance be shown by stable or lower reinvestment ratios stemming from sustained or higher levels of capital expenditures accompanied by even more rapidly rising cash flow. Therefore, improvements in reinvestment performance may not necessarily be associated with increases in the reinvestment ratio.

The reinvestment performance of the petroleum industry has varied greatly over the past decade.

UPSTREAM REINVESTMENT PERFORMANCE

	1979	1980	1981	1982	1983	1984	1985	First Half 1986
				$ billions				
Internal Cash Flow	5.1	6.7	5.2	5.8	7.3	8.4	9.5	2.9
Capital Expenditures - net of grants	5.1	6.9	5.9	4.9	5.1	6.1	7.3	3.0
				(%)				
Reinvestment Ratio	99	103	114	86	70	72	77	103

During the mid 70s, the upstream reinvestment ratio hovered around the 85% mark. Rising cash flow in 1979 and 1980 and the anticipation of even greater cash flow in future years spurred capital expenditures, resulting in higher ratios, 99% and 103%, respectively.

In 1981, however, a sharp decline in cash flow prompted the increase in the reinvestment rate to 114% despite the actual decline in capital expenditures. This was the result of the industry's inability to back away quickly from expenditure commitments when cash flow was severely eroded by the introduction of new energy taxes under the National Energy Program.

In 1983, the upstream reinvestment rate hit an all-time low at the same time as upstream cash flow began to rebound. The reinvestment rate increased marginally in 1984 and more dramatically in 1985 in anticipation of higher cash flow stemming from the Western Accord.

The time lag phenomenon experienced in 1981 and 1982 returned in the first half of 1986 and will likely continue through 1987. Upstream internal cash flow was sharply down from 1985. The reinvestment ratio rose to 103% for the first six months of 1986, as capital expenditures were largely committed for the first quarter 1986.

In 1987, the full impact of the cash flow decline and the current market uncertainty may cause the most severe expenditure cutback in the industry's recent history. This may translate into a decline in the reinvestment rate from the inflated 1986 level, regardless of PGRT relief which will, however, slow the erosion.

Under current circumstances, past performance may not be the appropriate yardstick for future investment behaviour. The industry's debt load at the end of 1985 was $24 billion compared to $9 billion in 1980. Also, outstanding preferred shares almost doubled over the same time span, in many instances as part of debt restructuring. Although the debt burden is quite unevenly distributed, the financial difficulties of some companies are affecting the reinvestment behaviour of the entire industry. For example, companies with strong balance sheets are maintaining flexibility by reserving capital for takeovers or asset acquisitions.

The severity of the situation is further amplified by the large asset write-downs in 1986 as these, of course, increased the relative weight of debt on companies' books[1] and thus force the repayment of debt.

When studying the reinvestment behaviour of the industry, operations other than upstream must also be considered. Several companies, especially the majors, have significant downstream and other Canadian and foreign operations. At times, these operations have been a drain on upstream cash flow. At other times, they have added a measure of stability to corporate cash flow.

Recent royalty reductions and the elimination of PGRT have positively contributed to the profitability of new investment projects.

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(1) The recent tightening of the Canadian Institute of Chartered Accountants' accounting rules has already stimulated the acceleration of such write-offs.

4. SURVEY METHODOLOGY

Several approaches were considered when the Minister of Energy, Mines and Resources asked the Agency to monitor the reinvestment intentions of the petroleum industry following the early elimination of the PGRT. These included:

1. Placing the burden directly on each company to justify its reinvestment performance, upon request.
2. Monitoring industry reinvestment performance using data acquired during the PMA's regular monitoring, even though then existing data would not allow all issues to be addressed. The current survey data (1986 Fiscal Year) reflects the full year 1986. Since that period would include only three months without PGRT (out of the 27 months for which PMA was to examine reinvestment intentions), the impact of its elimination would be incompletely captured.
3. Collecting proxy data, using federal, provincial and private sector sources, as appropriate. Data could be supplemented with expert opinion.
4. Augmenting the existing survey form to collect required data. An amendment to the regulations made under the Energy Monitoring Act would be required to change this form. The survey form, however, was seen to be too inflexible to capture the variety of behaviour expected.
5. Undertaking a special survey, with emphasis on spending intentions, initially independent of semi-annual monitoring activity but followed up through future regular data submissions. This option would involve an immediate survey of the companies' intentions and explicit business plans, followed up by the monitoring of implementation of these plans through the PMA's ongoing monitoring activity.

The last option was chosen because it offered the best means of informing the Minister and the public quickly and effectively about changes in the industry's spending plans flowing from the early elimination of the tax.

The PMA sent letters to 40 of the largest companies, explaining its mandate and approach, stating PMA's estimate of the company's PGRT relief and requesting cooperation in further discussions.

PMA staff visited 40 companies (Appendix C) and one bank to discuss the impact of PGRT relief, companies' expectations of future cash flow and their intentions for capital expenditures. Based on these discussions, the PMA provided each company with a summary of the principal determinants of its upstream capital expenditures and other key considerations. The companies were given the opportunity to comment on these notes which then formed the basis of this report's findings.

In 1986 the 40 companies surveyed represented:

- 96% of total corporate PGRT;
- 88% of industry's gross upstream revenue; and
- 80% of industry's net upstream capital expenditures.

The main characteristics of the 40 companies were:

- 6 integrated companies, 15 senior and 19 junior oil and gas producers;(1)
- 26 Canadian-controlled, 14 foreign-controlled;
- 20 taxable, 20 non-taxable;
- 25 publicly traded, 15 privately owned; and
- companies with debt as a percentage of capital employed ranging from 0 to 115%.

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(1) For PMA purposes, an integrated company is one with significant revenues in both the upstream (exploration, development, production, extraction and recovery of crude oil, natural gas, natural gas liquids and sulphur, as well as the production of synthetic oil) and downstream (refining, marketing, transportation and petrochemicals) segments. Senior and junior producers are companies that are predominantly exploration and production oriented with individually -- for the senior -- more than 1% of industry upstream revenues, or -- for the junior -- less than 1% of industry upstream revenues.

5. QUANTIFICATION OF THE PGRT RELIEF

PMA began its work by checking the amount of PGRT paid by reporting companies since 1981, and estimating the value of the tax relief. In 1985, for example, 114 companies paid a total of $2,029 million in PGRT. The table below gives the breakdown of payments for all years in which the tax was applied:

Year	PGRT Paid ($)	By Number Of Companies
1981	945,862,000	113
1982	1,649,246,000	108
1983	1,895,579,000	113
1984	2,176,476,000	122
1985	2,029,494,000	114
1986	441,243,000	74
	$ 9,137,900,000	

About 40 to 45 of the 120 companies reporting to PMA benefitted directly from the Government's action of repealing the tax 27 months ahead of schedule. For the remaining companies, the early elimination of PGRT had little or no affect. This is because the May 1986 increase in the small producers' exemption (from $500,000 to $2,000,000) had already effectively eliminated their PGRT liabilities (see Appendix A).

The companies favourably affected by the October 1 elimination of the tax represent in aggregate more than 80% of the industry's capital spending capability. Most of these are large oil and gas producers who belong to the Canadian Petroleum Association. Some have both upstream and downstream operations, i.e., they are involved in exploration, development and production of crude oil and gas, and in refining and marketing of petroleum products. The smaller producers in the group benefitting from PGRT relief typically belong to the Independent Petroleum Association of Canada and do not engage in downstream operations.

The PMA estimated the additional cash flow that should accrue to each of the top 40 companies as a result of early elimination of PGRT.

The estimate took into account that:

- PGRT had been scheduled to be phased out over a three-year period, with rates on conventional oil and gas dropping from 10% in 1986 to 8% in 1987 and 6% in 1988 (Appendix A, page 20).
- The mix of activity and the rates of PGRT varied from company to company. A company predominantly in oil sands production, for example, would pay far less PGRT than a company of similar revenue with activity mainly in conventional oil.
- For this analysis, an assumption has been made that the price of oil would stay at US$15 a barrel until December 31, 1988.

6. SURVEY RESULTS

A. Summary of Findings

- The internal cash flow of the top 40 companies of the Canadian petroleum industry will increase by about $1 billion[1] as a result of the accelerated elimination of the Petroleum and Gas Revenue Tax on October 1, 1986, twenty-seven months ahead of schedule. These 40 companies represent 88% of upstream revenue and 96% of PGRT paid in 1986.

- The removal of the tax -- closely followed by Alberta and Saskatchewan royalty reductions and royalty holidays, and by higher prices -- has improved the financial health of the industry as measured by the ratio of net internal cash flow to gross revenues. The removal of the tax has also prevented further cuts in employment.

- The accelerated elimination of PGRT was credited by company representatives as having given the industry new hope and was the impetus for a significant turnaround in attitude and outlook. It was praised as an essential recognition of the significant decline in the profitability of oil and gas operations in Canada.

- Industry exploration and development activities to the end of 1988 will be markedly higher than what they would have been without PGRT relief. However, this level is likely to be lower than the 1986 level because of the near halving of international oil prices, and the realization of significant long-term price uncertainty due to the continuing supply overhang.

- Based on the examination of companies' business plans, increased cash flow -- from either PGRT or royalty relief -- will not be used to raise dividends or to accelerate debt repayments.

- Despite governments' actions to reduce their take through the elimination of PGRT and the reduction in royalties, and the industry's efforts to cut costs at all levels, further rationalization of operations and restructuring are likely to occur.

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(1) This assumes an oil price of US$15/bbl; at US$18/bbl the cash flow improvement may amount to $1.3 billion.

STATISTICAL SUMMARY OF COMPANY RESPONSES TO ACCELERATED PGRT ELIMINATION

	Number of Companies	(%) of Industry*
1. Upstream Revenues	40	88
2. Investment Constraints		
a) Cash Flow	33	58
b) Opportunity	7	30
3. Effects of PGRT Relief on:		
a) Reinvestment Intentions		
i) Higher than Planned Prior to PGRT Relief	11	38
ii) 1987 Spending Higher than 1986	11	20
iii) Reduced Planned Spending Cutbacks	15	29
iv) No Change	3	1
b) Employment Intentions		
i) Increase	7	19
ii) Reduced Layoffs	16	45
iii) No Change	17	24
c) Dividend Payments on Common Shares		
i) Paid None in 1986	22	27
ii) Decrease in late 1986 or early 1987	6	15
iii) No Change Planned for 1987	12	47
d) Debt Repayment		
i) No Change	36	80
ii) Increase	4	8
4. Attitude Toward Acquisitions		
a) Not Seriously Interested	33	66
b) Seriously Interested	7	22

* Based on 1986 upstream revenues (preliminary)

B. Detailed Findings

1. As anticipated by government and industry, the elimination of the PGRT will result in higher industry cash flow and net income. The industry promised to use this incremental income to advance lagging capital expenditures and thereby increase employment. The interviews attempted to quantify the impact on capital expenditures, employment, debt repayment and dividends of the early elimination of PGRT.

2. The level of exploration and development activity depends on a number of complex factors. These fall into the following categories:

   i) Factors, forward looking, which determine the present value of investment projects and thus the quantity and ranking of investment opportunities; and

   ii) Factors which determine the industry's financial capability to proceed with economically acceptable investment opportunities.

   While investment opportunities, i.e. project profitability, were positively affected in April 1985 by the exemption from PGRT of all new production pursuant to the Western Accord, the accelerated elimination of PGRT in October 1986 had its economic impact on the latter category, in particular the cash flow factor.

   Factors determining investment opportunities are:

   - The geological potential of Canada, relative to that of other countries, especially the U.S.A.
   - Current and expected prices for oil and gas as determined by worldwide supply and demand developments.
   - Degree of Uncertainty Surrounding Price Expectations: Due to recent wide fluctuations in oil and gas prices, in addition to the sharp decline in 1986, industry now faces greater uncertainty in evaluating investment prospects.
   - Value of the Canadian Dollar:. Since international oil prices are denominated in US dollars, changes in the value of the Canadian dollar impact on Canadian producer revenues.(1)
   - Interest Rates: Current and expected interest rates affect borrowings, debt repayment, and hence expected returns and capital expenditures.
   - Fiscal Regime: The level of royalties and taxes to be paid on future production has a significant effect on producer net revenues, and thus project economics. Also, the degree of confidence in the stability of that system -- together with the perception of fairness -- enters industry consideration.

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(1) At US$18/bbl, a 3 cent rise in the value of the Canadian dollar vis-a-vis the US dollar is the equivalent of a $1 per barrel decline in Canadian producer revenues.

Factors determining reinvestment capability:

- Cash flow from current oil and gas operations has historically been a key determinant of upstream capital expenditures. Exploration spending in particular is generally financed only from equity or internal cash flow.

- Cash flow from other corporate activities, e.g. downstream operations, may supplement or drain funds available for upstream reinvestment.

- Investment climate influences industry's ability to attract new equity for exploration and new debt for development and production activities. An industry that is competitive in a worldwide context is more likely to attract investors.

3. Thirty-three of the 40 companies interviewed, representing 58% of industry by weight of revenue, were found to be cash flow constrained. In other words, these companies had more investment opportunities than they could fund through cash flow with oil prices in the range of US$15 to US$18 per barrel. Therefore, taking into account the fixed nature over the short term of dividends and debt repayment, higher cash flow from PGRT elimination (or reduced royalties or higher revenues) will result in increased capital expenditures.

   On examination of companies' business plans this close linkage has been fully confirmed. For almost all companies, the replacement of reserves -- and ideally the addition to reserves -- is a key objective of their corporate plans. Accordingly, cash flow will be spent.

4. Of the 40 companies for which business plans were obtained, seven face a combination of cash flow and investment opportunity constraints over the medium to longer term. These companies account for 30% of the industry's upstream activity. However, most of these companies will spend the expected incremental cash flow.

Companies commented extensively not only about their own but also about the industry's responses to cash flow changes. Even within the group of companies generally cash flow constrained, responses differed considerably.

5. While all companies have the capacity to react quickly to adverse developments such as lower prices or higher taxes, cash flow improvements (or capital injections) tend to produce increased economic activity less quickly in (a) non-conventional versus conventional areas and (b) in the case of larger compared to smaller members of the industry.

6. Differences in response time are not the result of arbitrary good or bad corporate behaviour, but simply a reflection of the remaining geological potential of the Western Canadian Basin (WCB) and the economic factors bearing on activities outside of the WCB and in the field of non-conventional technologies. The small producers, by their very nature, concentrate on conventional oil and gas operations and prospects of a scale which have not yet been fully explored. These companies have a capacity to quickly generate new economic activity in response to incentives, but their ability to add significantly to Canada's level of established reserves should not be overstated.

7. The large producers, if they wish to find sufficient volumes to replace their reserves and to remain going concerns, must aim at finding large pools in a relatively mature geological environment, concentrate on high-cost non-conventional production techniques or undertake costly high-risk frontier exploration. Consequently, the planning horizon lengthens considerably for these companies and all factors enumerated under item 2 will have to be taken into account. Therefore, price expectations, price uncertainty and future fiscal conditions weigh more heavily on reinvestment decisions. Inevitably, lead times are long, possibly longer than the reference period for this examination. Also, larger companies may try to smooth out the level of activity, thus maximizing efficiency in the utilization of resources.

8. For integrated companies, downstream cash flow may constitute a support of upstream exploration and development activity. To the extent that this cash flow deviates negatively from expectations, upstream reinvestment may be impaired. Such deviation could arise from the deferral for 90 days of price changes for refined products in response to crude price changes, as the delay puts out of phase domestic product price movements with international markets and consumer perceptions.

9. Employment is a major concern of both government and industry. Most of the beneficial employment impacts, stemming from increased exploration and development, occur in the industry's service sector. Yet cutbacks in employment in 1986 had to follow the large reductions in actual and planned capital expenditures, themselves the result of the sharp decline in oil prices. However, most companies have not cut staff to the bone: they remain staffed for activity hinging on an oil price 10% to 15% above that prevailing in September 1986, the time of the PGRT elimination announcement. The additional cash flow from PGRT relief was cited by almost every company as a significant factor in preventing further cuts.

   Some staff continue to be retained in the expectation of major projects proceeding soon. If these projects do not proceed, the staff affected may face layoffs.

10. Debt Repayment: Contrary to expectations, the added cash flow in 1987 and 1988 that companies will obtain due to the lower take by governments (lower Alberta royalties and elimination of PGRT) will not generally result in accelerated repayment of debt because:

    a) The majority of the 12 companies with debt above commercially acceptable levels had already established debt repayment schedules with their banks before the PGRT elimination was announced. These companies explained that the additional cash flow to be realized from early PGRT removal would not be used to speed up the already established repayment schedules, but to increase capital expenditures. Also, bankers were sensitive to the need to protect their clients' asset base.

    b) However, for two companies in this group, survival depends on reducing debt. At least some of the cash flow from PGRT relief may, therefore, contribute to debt reduction -- thus strengthening investment potential in the long run.

    c) In addition to the target group of the top 40 companies covered by this survey, there are many small companies which, following the collapse of oil prices, had to use current cash flow to pay down debt. For these companies the option of debt rescheduling either did not exist or was not realized due to a lack of assets or asset base diversity, or the absence of a management structure competent to make the necessary arrangements and commitments.

11. Dividend payments are a function of the financial performance of an entire corporate entity and not just of oil and gas production operations. Consequently, in the short term, reductions may only occur under severe circumstances; over the long term, increases or decreases in dividend payments will correlate with corresponding changes in profits. An analysis of dividends shows that:

    a) Of the 40 companies interviewed, 18 paid dividends in 1986, representing 61% of industry based on upstream revenues;

    b) Six companies -- representing 15% of revenue -- reduced dividend payments in late 1986 or early 1987;

    c) No company planned to increase its dividends following the elimination of PGRT.

12. Acquisitions are actively considered by seven of the 40 companies and another five would be ready to respond to opportunities with a 'good fit' should they present themselves. However, a simple picture did not emerge:

    a) Most actively operating companies consider or wish to feel free to consider the acquisition of undeveloped reserves, producing properties and entire corporate entities as an alternative to, if not as a logical extension of, the direct exploration for reserves in pursuit of the corporate objective to stay in business and to grow.

    b) The issue is therefore in the first instance an economic one: can reserves be bought for less than it would cost to explore and develop them -- presumably on an after-tax basis. Several companies pointed out that the tax system favoured exploration over acquisition.

    c) Most companies interviewed stated that they preferred to find their own reserves -- presumably at lower costs. Only in the case of two companies did it appear that viability as an on-going oil and gas operator is inextricably linked to the acquisition path. Awareness of public policy concerns regarding the acquisition of Canadian-controlled companies was also a factor.

    d) Despite the economic difficulty for companies with large corporate debt following the oil price collapse, acquisitions are very hard to make, according to companies of all camps:

        - Banks as lenders to companies with current cash flow difficulties, have taken the long view of the petroleum market, relying on borrowers' asset values, good management and a recovery of markets -- thus not forcing their clients into receivership but instead showing great flexibility in accepting debt rescheduling proposals.

        - The uncertainty surrounding oil and gas markets, in terms of both price and volume, has kept buyers' and sellers' prices far apart: though potential buyers evaluate oil and gas assets already in their possession at prices similar to the asking price of sellers, they expect significant discounts when further extending their exposure in the oil and gas business. In other words, in today's highly uncertain environment, sellers are expected to absorb a good measure of the market risks. Only those buyers which are not yet deep enough into oil and gas can be expected to conclude deals by sharing the interest risks with a seller.

    e) In terms of mergers, both large and small companies consider the Alberta Royalty Tax Credit program as an incentive to remain small and independent.

APPENDICES

Appendix A

HISTORY OF THE PETROLEUM AND GAS REVENUE TAX

Effective Date	Major Actions - Announcement Date
	The Petroleum and Gas Revenue Tax was announced October 28, 1980 as part of the **National Energy Program**. The PGRT was a tax on production revenue. Production revenue was defined in the PGRT Act (S.C. 1980-81-82-83, c. 68, Part IV) as the aggregate of production income and royalty income.
January 1, 1981	PGRT became effective at a rate of 8% of gross revenue less operating costs.
January 1, 1982	The **energy pricing agreements** with the producing provinces in late 1981 led to a doubling of the PGRT rate to 16%. Simultaneously, a 25% resource allowance was established, reducing the new 16% rate to an effective 12% rate for most taxpayers. The Incremental Oil Revenue Tax (IORT), a tax on windfall profits, was also established under the energy agreements.
June 1, 1982	With the **NEP Update** announced May 31, 1982, the PGRT was reduced from 16% to 14.67%. Because of the 25% resource allowance, this meant the new effective rate for non-synthetic production was 11%. As well, the effective oil sands rate was lowered to 8%. A Small Producer's PGRT Credit was also introduced, whereby the first $250,000 of PGRT otherwise payable on production revenue was exempted. IORT rate was generally reduced to nil for the period June 1982 to May 31, 1983.
January 1, 1983	The **April 19, 1983 Budget** announced the introduction, retroactive to January 1, 1983, of the Cumulative Enhanced Recovery Capital Expense (CERCE). This tax relief was designed to encourage the recovery of conventional light and heavy crude oil through tertiary recovery projects. The PGRT on production revenue from the project's reservoir would not become payable until the eligible capital costs of the project were recovered by the participant. The resource allowance and small producer PGRT exemption would be determined on the basis of the petroleum and gas revenues as reduced by these capital investments. The April 1983 Budget also extended the IORT suspension to May 31, 1984. The **February 1984 Budget** extended the IORT suspension to May 31, 1985.

Effective Date	Major Actions - Announcement Date
January 1, 1985	The **Economic and Fiscal Statement of November 8, 1984** included an increase in the Small Producer's Credit from $250,000 to $500,000.
January 1, 1985	The **May 1985 Budget** eliminated the IORT effective January 1, 1985.
April 1, 1985	The **Western Accord** of March 28, 1985 provided for the phasing out of the PGRT by December 31, 1988. The phase-out was to be accompanied by the following effective rate changes:

Year	Gas & Conventional Oil	Oil Sands
1986	10%	6%
1987	8%	4%
1988	6%	2%
1989	0%	0%

As well, the PGRT was eliminated totally for the following types of production:

- production from wells drilled or deepened after March 31, 1985 (new production);
- major new energy projects commenced after March 31, 1985;
- incremental production from new or expanded waterflood projects commenced after March 31, 1985; and
- post March 31, 1985 incremental production from tertiary oil recovery projects which commenced operation after December 31, 1982.

A cumulative offset account was introduced whereby 30% of the new unused write-offs of exploration and development expenditures after March 31, 1985 could reduce a corporation's PGRT payable.

January 1, 1986	Implementing a provision of the Western Accord, the first $10,000 of an individual's annual resource income was exempted from PGRT. This, however, was superseded by an announcement of April 30, 1986, raising the exemption to $40,000, retroactive to January 1, 1986.
May 1, 1986	The April 30 announcement also increased the **Small Producer's Credit** from $500,000 to $2,000,000 annually, and eliminated the tax for the Syncrude and Suncor oil sands plants for the remainder of 1986.
January 1, 1986	Announcements of September 17 and October 24, 1986 further modified the exemption by permitting corporations and individuals to include up to $1.5 million of annual **royalty income** in the income qualifying for the small producer credit.
October 1, 1986	The Minister of Energy, Mines and Resources announced, September 8, 1986, the **accelerated elimination of the PGRT.**

Appendix B

COMPONENTS OF UPSTREAM REVENUE

	1979	1980	1981	1982	1983	1984	1985	First Half 1986
	$ billions							
GROSS UPSTREAM REVENUE	12.6	16.1	17.4	21.0	23.9	26.4	27.7	9.1
Interest Charges	-	-	1.0	1.6	1.4	1.6	1.6	0.8
Operating and Other Costs	2.6[a]	3.5[a]	3.8	4.2	4.4	4.9	5.4	2.7
NET OPERATING REVENUE	10.0	12.6	12.6	15.2	18.1	19.9	20.7	5.6
Royalties	3.9	4.9	5.0	5.6	6.1	6.4	6.3	1.8
PGRT	-	-	0.9	1.6	1.9	2.2	2.0	0.4
Corporate Taxes (except PGRT)	1.0	1.0	1.4	2.2	2.8	3.0	3.1	0.5
INTERNAL CASH FLOW	5.1	6.7	5.3	5.8	7.4	8.4	9.4	2.9
	(%)							
NET OPERATING REVENUE - as a per cent of gross revenue	79	78	72	72	76	75	75	62
INTERNAL CASH FLOW - as a per cent of gross revenue	40	42	31	28	31	32	34	32

NOTE: (a) Includes interest charges

Figures may not add due to rounding.

Appendix C

COMPANIES SURVEYED

Aberford Resources Ltd.
Alberta Energy Company Ltd.
Amerada Minerals Corporation of Canada Ltd.
Amoco Canada Petroleum Company Ltd.
Anderson Exploration Ltd.
ATCOR Ltd.
BP Canada Inc.
Canadian Hunter Exploration Ltd.
Canadian Occidental Petroleum Ltd.
Canterra Energy Ltd.
Chevron Canada Resources Limited
Dome Petroleum Limited
Esso Resources Canada Limited
Gulf Canada Corporation
Home Oil Company Limited
Husky Oil Ltd.
ICG Resources Ltd.
Maligne Resources Limited
Mobil Oil Canada, Ltd. (includes Canadian Superior Oil Ltd.)
Murphy Oil Company Ltd.
Norcen Energy Resources Limited
North Canadian Oils Limited
Oakwood Petroleums Ltd.
Ocelot Industries Ltd.
PanCanadian Petroleum Limited
Pembina Resources Limited
Petro-Canada Inc.
Placer CEGO Petroleum, A Division of Placer Development Limited
Sceptre Resources Limited
Shell Canada Limited
Sulpetro Limited
Suncor Inc.
TCPL Resources Ltd.
Texaco Canada Resources Ltd.
Total Petroleum (North America) Ltd.
Universal Exploration (83) Ltd.
Unocal Canada Limited
Westcoast Petroleum Ltd.
Western Decalta Petroleum (1977) Limited
Westmin Resources Limited